PB-232 376

FACTORS AFFECTING ABILITY TO RETROFIT FLUE GAS DESULFURIZATION SYSTEMS

RADIAN CORPORATION

PREPARED FOR
ENVIRONMENTAL PROTECTION AGENCY

8 DECEMBER 1973

DISTRIBUTED BY:

NTIS
National Technical Information Service
U. S. DEPARTMENT OF COMMERCE

FORM NTIS-181
(1-24-74)

ACCESSION NO.
PB-232 376

U.S. DEPARTMENT OF COMMERCE
NATIONAL TECHNICAL INFORMATION SERVICE

SIR (SPECIAL INTEREST REPORT) SELECTION/REVIEW

AFTER PROCESSING RETURN THIS FORM TO A&E, ROOM 2014, SILLS BLDG.

SCREEN	COMMENT
DOWD	
LEHMANN	☐ BEST (IN A BIG FIELD) ☑ GOOD (SMALL FIELD) ☐ MODEL SYSTEM ☐ NO _____

REVIEW	YES	NO	COMMENT
ALEXANDER			
BEH			
BJORGE			
JOSEPHS			
RYERSON			
DECISION			DISCLAIMER ☐ YES _____ INT.
PRICE	$3.75/1.45		

USCOMM-DC 6859-P74

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RE
EPA-450/3-74-015		PB 232 376

4. TITLE AND SUBTITLE
Factors Affecting Ability to Retrofit Flue Gas Desulfurization Systems

5. REPORT DATE
8 December 1973

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)
NA

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Radian Corporation
8500 Shoal Creek Boulevard
P. O. Box 9948
Austin, Texas 78766

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.
No. 68-02-0046

12. SPONSORING AGENCY NAME AND ADDRESS
U. S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

13. TYPE OF REPORT AND PERIOD COVERED
Final Report

14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT

The report presents results of a study of application of flue gas desulfurization technology to steam-electric power plants and the rate at which systems may be installed. The report focuses on lime and limestone but also considers magnesium oxide and sodium based scrubbing processes. Factors to be considered in wide-scale application of flue gas cleaning processes include the capability and willingness of vendors to supply the systems, time requirements, labor availability, lead time equipment delivery, and the availability of capital and engineering construction services. Ground space for equipment in proximity to the boiler and stack was found to be a key factor. Flue gas desulfurization process economics and cost estimates are presented showing how major factors including equipment requirements, plant load factor, plant operating life, mode of solid waste disposal, and byproduct revenues affect costs. The information was developed for power plants in the State of Ohio but much of it is generally applicable to U. S. installations.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Combustion Products	Air Pollution Control	13B
Sulfur Dioxide	Sludge Disposal	Electric Power Plants	
Coal	Installing		
Sulfur	Boilers		
Limestone	Cost Estimates		
Calcium Oxides	Magnesium Oxides		
	Sodium Inorganic Compounds		

Reproduced by
NATIONAL TECHNICAL
INFORMATION SERVICE
U S Department of Commerce
Springfield VA 22151

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
Unlimited	Unclassified	67
	20. SECURITY CLASS *(This page)*	22. PRICE
	Unclassified	$3.75/1.45

EPA Form 2220-1 (9-73)

EPA-450/3-74-015

FACTORS AFFECTING ABILITY TO RETROFIT FLUE GAS DESULFURIZATION SYSTEMS

by

Radian Corporation
8500 Shoal Creek Boulevard
P. O. Box 9948
Austin, Texas 78766

Contract Number 68-02-0046

EPA Project Officer: Robert T. Walsh

Prepared for

ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Water Programs
Office of Air Quality Planning and Standards
Research Traingle Park, N. C. 27711

December 1973

This report was furnished to the Environmental Protection Agency by the Radian Corporation, Austin, Texas, in fulfillment of Contract No. 68-02-0046. The contents of this report are reproduced herein as received from the Radian Corporation. The opinions, findings, and conclusions expressed are those of the author and not necessarily those of the Environmental Protection Agency. Mention of company or product names is not to be considered as an endorsement by the Environmental Protection Agency.

Publication No. EPA-450/3-74-015

TABLE OF CONTENTS

		Page
1.0	INTRODUCTION.	1
2.0	DESIGN FACTORS AFFECTING APPLICABILITY OF FLUE GAS CLEANING PROCESSES TO EXISTING BOILERS	4
	2.1 Flue Gas Cleaning Space Requirements	5
	2.1.1 Lime/Limestone Scrubbing.	6
	2.1.2 Magnesium Oxide Scrubbing	9
	2.1.3 Regenerable Alkali Scrubbing (e.g., Wellman-Power Gas Process).	10
	2.2 Potential Retrofit Space Available at Typical Existing Boilers	10
3.0	RETROFIT PROCESS ECONOMICS.	13
	3.1 Capital Investment	13
	3.2 Operating Costs.	18
	3.3 Annualized Costs and Present Worth of Flue Gas Cleaning.	23
4.0	APPLICATION OF TECHNICAL AND ECONOMIC FACTORS TO THE OHIO BOILER POPULATION	27
	4.1 Expected Retrofit Space Availability in Ohio	31
	4.2 Estimated Cost of Flue Gas Cleaning for Existing Ohio Boilers.	34
5.0	FACTORS WHICH MAY LIMIT THE RATE OF APPLICATION OF FLUE GAS CLEANING IN OHIO.	39
	5.1 Capital Requirements	40
	5.2 Power Availability	40
	5.3 Demand and Supply of Critical Labor Categories in Ohio	41
	5.4 Major Equipment Supplies	43

TABLE OF CONTENTS (Cont.)

		Page
	5.5 Tie-In Requirements.	46
	5.6 Availability of Engineering and Design Services	47
	5.7 Vendor Capability.	47
6.0	SUMMARY	49
	BIBLIOGRAPHY	
	APPENDIX	

1.0 INTRODUCTION

Air pollution control regulations adopted by the State of Ohio call for reduction of sulfur oxides emissions in certain high priority areas of the state to 1.8 milligrams or less SO_2 per Kcal heat input (1 lb SO_2/million BTU) by July 1, 1975. Sources in second and third priority regions must reduce emissions to 2.9 and 5.8 milligrams SO_2 per Kcal (1.6 and 3.2 lb SO_2/million BTU) by the same date. Sources in all areas of the state must meet the 1.8 milligram SO_2 standard by July 1, 1978. These emission rates correspond to a coal sulfur content of roughly .5-.6 percent by weight. Flue gas cleaning systems are the primary option for meeting this emissions standard.

Although flue gas cleaning technology is now available for general use, there are several limitations on both the extent of practical application and the rate at which systems may be installed. This is particularly the case for control of existing boilers.

This study addresses the technical and economic factors associated with application of flue gas cleaning systems to existing coal-fired boilers in Ohio. The present discussion considers lime/limestone, magnesium oxide, and sodium based scrubbing processes. While catalytic oxidation is also considered a commercially available SO_2 control process, it is generally more applicable to new boilers than existing boilers. Particular attention is given to lime/limestone scrubbing systems since these are presently regarded as most technically advanced and widely applicable. Major technical and economic trends illustrated in the following sections are expected to apply to each of these flue gas cleaning methods, however.

In Section 2.0, a general description of each process is given. Since technical and operational aspects of flue gas cleaning systems will be discussed in related reports, emphasis is placed on the question of process applicability. The controlling factor appears to be availability of ground space for equipment located immediately adjacent to the boilers and stacks.

Flue gas cleaning process economics are discussed in Section 3.0. Cost estimates are given which show how major factors including capital investment, operating costs, plant load factor and operating life, and solid waste disposal costs affect the economic viability of lime/limestone wet scrubbing processes. This discussion should provide a framework for application of more specific economic information developed by other contractors.

Technical and economic information developed in Sections 2.0 and 3.0 is applied specifically to the existing Ohio boiler population in Section 4.0. Boiler size, age, and load factor distribution are discussed and used to estimate flue gas cleaning applicability. Estimated control costs are presented as a function of degree of required retrofit.

Section 5.0 addresses additional factors which must be considered in wide-scale application of flue gas cleaning processes. Included here are such things as the capability and willingness of vendors to supply the systems during a given time frame, the effects of major construction projects on labor markets, the availability and lead time for large manufactured items such as pumps, fans, and grinding mills, the availability of engineering/construction services, and the availability of capital. Although a considerable amount of flue gas cleaning

capacity should be technically and economically reasonable in Ohio, some or all of these factors may limit the rate of application of the processes. Some problems faced in Ohio can be expected to be particularly troublesome since more than 12% of all coal-fired generating capacity in the United States is located in Ohio.

In the concluding section, technical and economic limitations on flue gas cleaning application are briefly discussed in terms of the present Ohio emissions standards and compliance schedule.

2.0 DESIGN FACTORS AFFECTING APPLICABILITY OF FLUE GAS CLEANING PROCESSES TO EXISTING BOILERS

There are three general classes of design problems associated with flue gas cleaning systems. These are:

- Process Design
- Process Control
- Mechanical Design

The first of these involves specification of process equipment needed to prepare raw materials, treat a given quantity of flue gas, remove the required amount of SO_2, and dispose of resulting solid wastes. The process design is primarily concerned with equipment sizes and is normally based on limiting criteria for plant performance (for example, 100% load using 3.5% sulfur coal). All objectives must be accomplished with a reasonable degree of process reliability.

The second design problem naturally arises when operating conditions change from those specified as a "base case". Power plant boilers do not operate at constant capacity nor do they burn a constant quality fuel over the plant life. Some form of process control system is required to maintain system performance under varying or unusual conditions. A common control objective in limestone scrubbing, for example, is to maintain a certain slurry pH. This may be done by adjusting the rate of limestone added to the process. Poor SO_2 removal will result from too little limestone; formation of scale on equipment surfaces can be caused by too much.

Existing boiler operating parameters will definitely affect process design and control problems and probably the reliability of an installation. There are no specific conditions other than equipment space requirements, however, which would actually prevent application of the three flue gas cleaning processes considered. For this reason, these aspects of flue gas cleaning application will not be discussed here.

Mechanical design will have a significant effect on process applicability. Technical limitations on flue gas transport (primarily heat and pressure losses associated with long lengths of duct) require that certain pieces of process equipment be physically located adjacent to the boiler and stack. This may not always be practical for a given existing unit. Space requirements for flue gas cleaning processes are discussed in detail below.

2.1 Flue Gas Cleaning Space Requirements

Information on flue gas cleaning space requirements may be developed from general process design criteria. Comparison of required and existing space for a large number of existing boilers will then indicate the degree of retrofit which might be reasonable from a purely technical standpoint. While total ground space requirements for different flue gas cleaning processes vary somewhat, the three scrubbing methods considered here all require essentially the same equipment in the critical area adjacent to the boiler and stack. Since other portions of the system may be located in peripheral areas, the overall space needed is not as significant to the retrofit problem. The fact that the scrubbing processes are roughly

equal with respect to retrofit space requirements must be distinguished from process applicability, however. Many factors not discussed here enter into process selection.

2.1.1 Lime/Limestone Scrubbing

The basic principles of all lime/limestone scrubbing processes are essentially the same. An alkaline additive, lime or limestone, is introduced to the system as a solid to form a slurry which is used as the scrubbing liquor. The reaction with SO_2 from the flue gas takes place in the liquid phase to form a waste product mixture of $CaSO_3 \cdot \frac{1}{2}H_2O$ and $CaSO_4 \cdot 2H_2O$ solids which precipitate from the liquid phase. Major process equipment includes the scrubber where contact between the flue gas and slurry is promoted, a mist eliminator for removal of entrained liquid from the SO_2-lean gas, a hold or delay tank where additional lime/limestone dissolution and solid product precipitation occurs, and a solids separation device to reduce the amount of liquid waste leaving the process. Partial reheating of the flue gas may also be required to avoid plume "droop" and high ambient SO_2 levels. In addition to the equipment listed above, several other items are needed. Storage bins for the alkaline additive are needed. Slurry tanks and slurry pumps are also required. For the limestone process, ball mills are necessary for grinding the raw limestone to the proper mesh size. A waste sludge handling area is required for both the lime and limestone systems. Depending on whether on-site solids disposal is planned, equipment in this area could include a clarifier or thickener, vacuum filters or sludge fixation equipment. Space may also be needed for intermediate or "live" sludge storage.

Space required for the scrubbing section of this process is the major concern for retrofit since this equipment must be placed adjacent to the powerhouse and stack. Process equipment outside of the scrubber area is of less concern to the retrofit problem since it can be located on the peripheral areas of the plant.

The most important parameter to consider when sizing the scrubber area is gas velocity through the scrubber(s). Typical gas velocities for SO_2 absorption in a spray tower, for example, are about 2.9 M/sec (9.5 ft/sec). This may vary somewhat with the vendor and type of scrubber. Assuming each scrubber handles 765,000 M^3/hr (450,000 ACFM), a gas velocity of 2.9 M/sec (9.5 ft/sec) corresponds to a scrubber cross-sectional area of about 74 square meters (800 square feet) or scrubber dimensions of 6.1 meters by 12.2 meters (20 feet by 40 feet).

Hold tank volume depends on the rate of sulfur-solids precipitation required. For a boiler burning 3.5% sulfur coal, a 765,000 M^3/hr (450,000 ACFM) scrubber module designed to meet the 1978 Ohio standard of 1 lb SO_2 emitted per million BTU heat input would require a hold tank of approximately 15 meters (50 feet) in diameter and 17 meters (55 feet) high. The recommended tank size could vary considerably from vendor to vendor and may also change as new process information and designs are developed. The mist eliminator size is of little concern to ground space requirements but may present some problems with vertical spacing. It is usually placed above the scrubber and typically is about twice the height of the scrubber.

As an example of the total ground space requirements for the scrubbing section of a lime/limestone unit, consider a 550 Mw boiler with four scrubbers and four hold tanks with the dimensions mentioned above. The hold tanks are placed beneath the scrubbers to conserve ground space. If 4.6 meters (15 feet) between the hold tanks and 2.3 meters (7.5 feet) from the hold tanks to the pump houses are allowed and if the pump houses are assumed to be 9.2 meters (30 feet) by 18.4 meters (60 feet), a total ground space of 57.9 M x 39.6 M (190 ft x 130 ft) or 2295 square meters (24,700 square feet) will be required. This can be expressed as an area per megawatt, giving about 4.2 square meters/Mw (45 square feet/Mw).

The area of the scrubbing section can be reduced by placing the hold tanks at some peripheral area instead of between the powerhouse and the stack or by reducing their size to fit completely under the scrubbers. For the scrubber dimensions listed above and with allowances of 4.6 (15 feet) between scrubbers and 3 meters (10 feet) between the scrubbers and the pump houses, a total area of about 1217 square meters (13,100 square feet) or 2.2 square meters/Mw (23.8 square feet/Mw) will be required.

The above estimate of scrubber area per megawatt not only represents the space requirements for a 550 Mw plant but is relatively independent of plant size. It can be roughly applied to all boilers burning coal with similar heat and sulfur content. The ground space needed for the scrubbing section is directly proportional to the size of the plant since scrubber cross-sectional area design is proportional to the flue gas flow rate.

Obviously space requirements are subject to some variation. The scrubber-hold tank modules may be crowded closer together than assumed here. This would depend upon the individual plant situation. Also, variations in scrubber and hold tank designs may allow the retrofit to be made in a slightly smaller area, again depending upon the plant characteristics.

2.1.2 Magnesium Oxide Scrubbing

This process utilizes a slurry of MgO and recycled $MgSO_3$ and $MgSO_4$ solids as the absorbing liquor. After being cooled in the air preheater, flue gas enters the scrubber and contacts the slurry. The effluent from the scrubber is thickened to remove fly ash, then sent to a crystallizer and centrifuge where hydrated crystals of $MgSO_3$ and $MgSO_4$ and unreacted MgO are separated from the mother liquor. The liquor is recycled to the scrubber and the centrifuged wet cake is dried in a rotary kiln. Dried anhydrous crystals may be sent to an off-site plant where they are calcined to recover MgO and SO_2. The regenerated MgO is reslurried to maintain SO_2 sorption in the scrubber. The SO_2 gas is used for sulfuric acid or sulfur manufacture. Major process equipment includes the scrubber, slurry tank, fly ash separator, crystallizer, centrifuge, and drying kiln.

The major pieces of equipment which are placed in the scrubbing area are the SO_2 absorbers, MgO slurry tank, mother liquor tank, and flue gas ducts. The scrubbing section will require essentially the same ground space as in the lime-limestone scrubbing section. Since the scrubber ground space required is directly proportional to the flue gas flow rate, as in the lime/limestone scrubbers, the area required should not change significantly on a per megawatt basis.

2.1.3 Regenerable Alkali Scrubbing (e.g., Wellman-Power Gas Process)

In this process, flue gas from boilers is washed by a prescrubber to remove the greater part of solids and SO_3 in the gas. A concentrated solution of Na_2SO_3 and $NaHSO_3$ is used as the scrubbing liquor. Exiting the scrubber, the absorbent is heated with steam to yield 90% SO_2 gas and Na_2SO_3 crystals which are recycled. The high purity, high concentration SO_2 gas can be further processed to liquid SO_2, sulfur, or H_2SO_4. In Japanese installations of this process, waste water from the prescrubber is filtered, oxidized by air and a small quantity of H_2SO_4, and neutralized with slaked lime before being discharged as a 10% Na_2SO_4 solution. However, additional treatment may be required for application in the United States. Major process equipment for this process includes the scrubber, mix tank, evaporator-crystallizer, and the centrifuge separator. An acid or sulfur plant is generally required on the site to treat the off gas from the evaporator-crystallizer.

The space for the scrubber section of this process should not be different from the other two processes since the scrubber area is again proportional to the flue gas flow rate.

2.2 Potential Retrofit Space Available at Typical Existing Boilers

In order to examine the retrofit problem from a technical viewpoint, the required space estimated in Section 2.1 must be compared to the existing space at power plants. In 1972, the M. W. Kellogg Company reported results for a survey of available retrofit space at 103 plants across the United States in both urban and rural areas (KE-083). Visits by

Kellogg personnel were made to the power plants, and available space was determined from plot plans of each power station.

In Section 2.1 it was shown that a minimum area of 2.2 square meters/Mw (24 square feet/Mw) is required for retrofit installation of SO_2 scrubbing equipment, although this number is subject to some variation. For the purposes of this discussion, it is assumed that any unit with available area of less than 1.9 M^2/Mw (20 ft^2/Mw) can be retrofitted only with great difficulty. Using this criterion size and age distributions for retrofittable capacity surveyed by Kellogg were calculated. These distributions are shown in Figure 2-1.

The overall impact of the Kellogg survey is clearly indicated. A high percentage of large, new boilers have sufficient space for flue gas cleaning systems. More than 87% of the surveyed units ten years old or less may be retrofitted. About 85% of capacity in existing units larger than 500 Mw have sufficient space.

In terms of total capacity, about 70% can be retrofitted by including only boilers less than 20 years old or greater than 100 Mw capacity. Since small, old units are less likely to have space and do not account for a significant portion of total capacity, little additional overall control could be gained by extending flue gas cleaning beyond these limits. About 74% of the total capacity surveyed had scrubber area space equal to or greater than the estimated 1.9 M^2/Mw (20 ft^2/Mw) required.

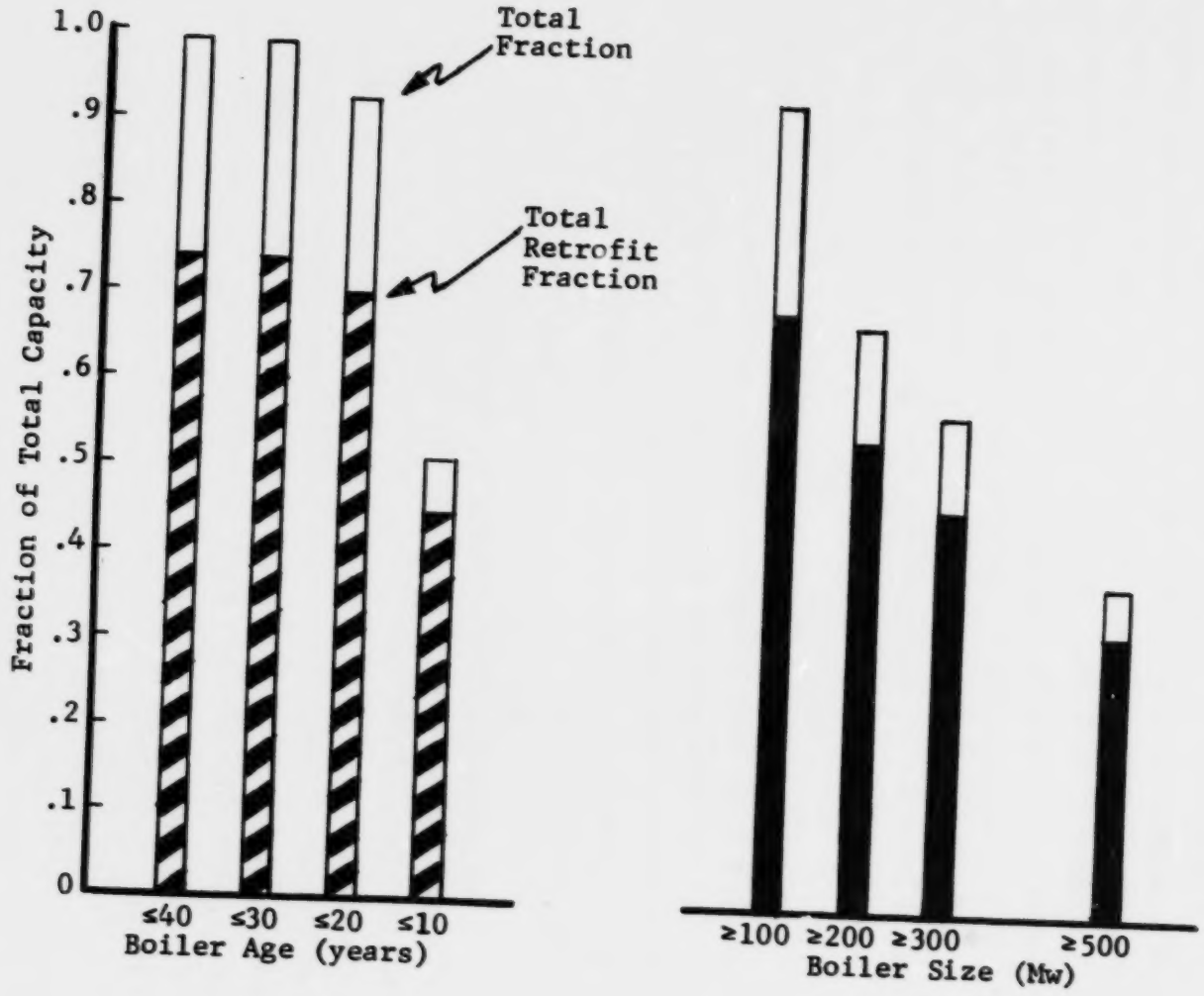

FIGURE 2-1 - FRACTION OF TOTAL RETROFITTABLE CAPACITY IN U. S. VERSUS AGE AND SIZE
(Based on Space Requirements)

3.0 RETROFIT PROCESS ECONOMICS

In Section 2.0, technical factors limiting the application of flue gas cleaning processes to existing units were discussed. The availability of space was shown to be of primary importance. In this section, the economics of flue gas cleaning are considered. In addition to capital investment and annual operating costs, expected operating life and load factor (annual power produced by a unit divided by the rated output) for a boiler have a major impact on the overall economics of flue gas cleaning. Economic factors discussed below, like technical considerations shown in Section 2.0, make overall process feasibility a strong function of boiler size and age.

3.1 Capital Investment

Installation costs for flue gas cleaning system on an existing boiler are dependent on three major design parameters. These are:

- unit size (essentially proportional to gas flow rate),
- required SO_2 removal rate,
- difficulty of retrofit installation.

Many capital cost estimates for flue gas cleaning processes have appeared in the literature. A recent detailed cost estimate for a typical limestone scrubbing process was prepared for EPA by Catalytic, Incorporated and reported in January of 1973 (CA-107). Rochelle (RO-082) has presented recent estimated and

installed capital costs for eight flue gas cleaning methods including both regenerative and non-regenerative processes.

For purposes of discussion, a quantitative breakdown of capital costs estimated by Catalytic for a limestone scrubbing unit is summarized below.

TABLE 3-1

Typical Capital Investment for a Limestone Scrubbing Unit (Including Particulate Removal)

Basis: New 500 Mw Boiler, 3.5% Sulfur Coal

Equipment Classification	Function	Total Installed Cost (Thousands of Dollars)
I and II	Limestone Preparation and Handling	1,522
III	Flue Gas Scrubbing System	7,124
IV	Fans, Ducts, and Dampers	2,809
V	Flue Gas Reheat	550
VI	Sludge Handling and Disposal	6,255
VII	Mist Elimination	342
VIII	Major Electrical Equipment	451
IX	Miscellaneous Field Costs	1,041
	Total Installed Cost	$20,094

Certain portions of these system costs are sensitive to the three major design parameters listed above.

As discussed in Section 2.0, the size of equipment in contact with the flue gas stream is directly proportional to the volume of gas being scrubbed. Thus, the size of Equipment Groups III, IV, V, and VII are proportional to the size of the boiler being retrofitted. Equipment in these groups accounts for 52% of the total installed cost. Equipment sizes in Groups I, II, and VI are proportional to the amount of SO_2 being removed. This is in turn dependent on the amount of sulfur in the fuel, the size of the boiler, and the degree of control required. These equipment groups account for 37% of the total system cost.

Other process equipment included in Groups VIII and IX may have varying relationships to the unit size and the amount of SO_2 removal.

Equipment costs are generally less than directly proportional to equipment size. That is, some savings in terms of cost per unit size is realized in construction of larger pieces of equipment. This savings no longer applies, however, when equipment reaches a maximum feasible unit size. Many of the pieces of equipment used in flue gas scrubbing systems are subject to such "modular" size limitations.

There are many factors dictating maximum sizes for equipment. Examples include difficulty in shipping an field erection as well as technical limitations in manufacturing. Variations in maximum available equipment sizes complicate cost engineering and estimating for flue gas cleaning systems. Expected effects of unit size and fuel sulfur content on capital investment for limestone scrubbing are summarized in Figure 3-1. These were estimated using appropriate cost versus size factors for equipment groups shown in the previous table. A substantial savings in capital investment on a per kilowatt basis is seen for large plants. The cost variations due to fuel sulfur content are substantial, but less pronounced

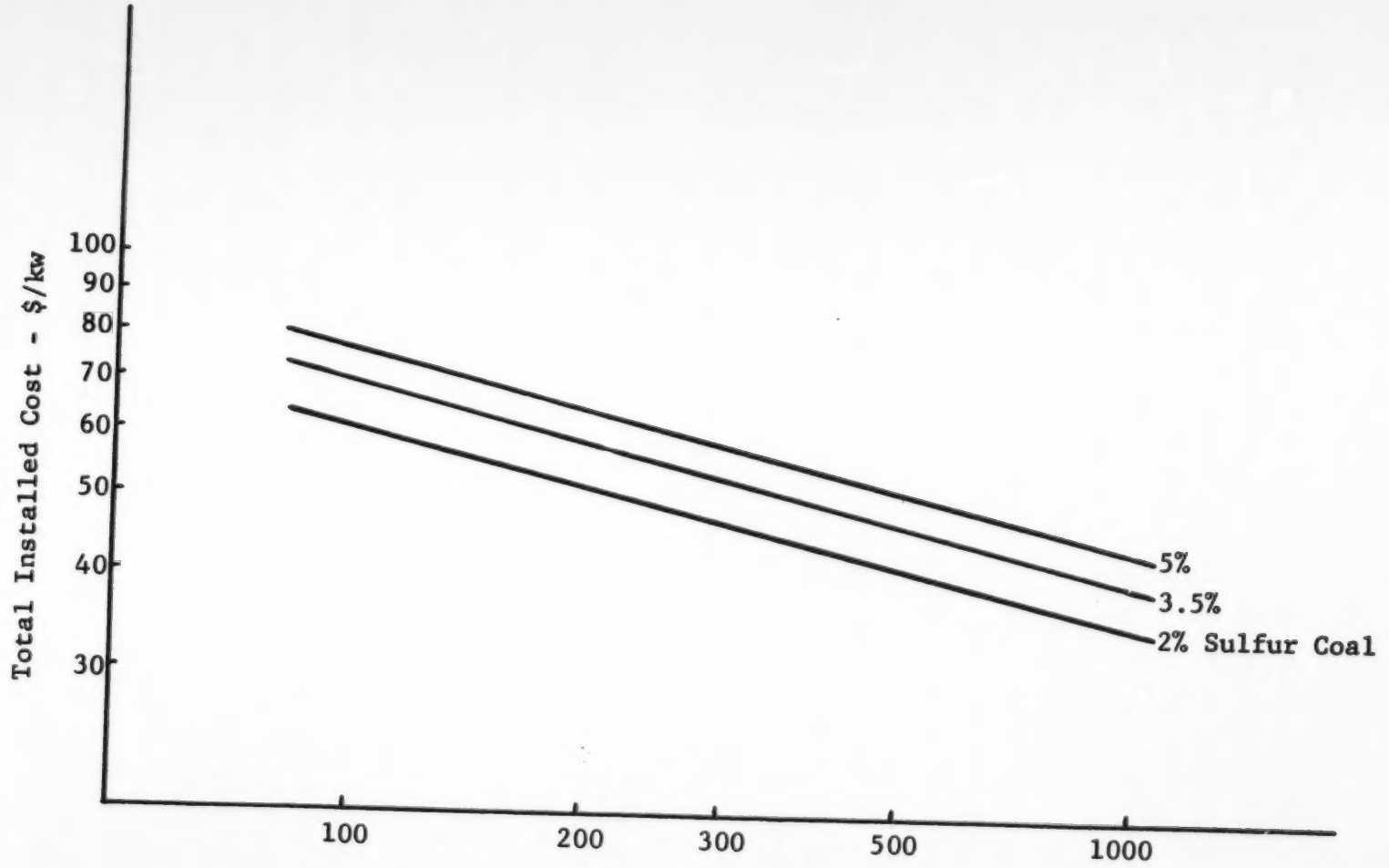

Figure 3-1
Effect of Unit Size and Coal Sulfur Content
on Limestone Scrubbing Capital Investment
(Retrofit)

than the size effect since a smaller percentage of the equipment is affected by the amount of SO_2 removal.

In addition to the amounts of flue gas treated and SO_2 removed, the location and layout of existing boilers exert a major influence on installed capital costs. Installed costs of Equipment Groups III, IV, V, and VII in the example estimate are sensitive to availability of space and difficulty of installation. These portions of the system account for approximately 50% of the total system capital cost. The total system cost may thus increase considerably in a particularly difficult retrofit situation.

The Catalytic, Inc. cost estimate referenced above includes a comparison between new and retrofit installation costs for the same unit design. For the retrofit installation, increased piping and duct work combined with more complicated layout and structural problems leads to an increased cost of six million dollars over the original 20 million dollar estimate.

A comparison between two recently installed limestone scrubbing units by the same vendor (Babcock and Wilcox) serves as an additional illustration of costs of retrofit versus new installations. The installed cost for Commonwealth Edison's 177 Mw Will County Station was 13.3 million dollars or $75/kw. This unit is regarded as a difficult retrofit on a relatively small boiler. A large new system at Kansas City Power and Light's LaCygne Station (820 Mw) is reported to have cost 32.5 million dollars or $40/kw. Using the cost versus size dependence shown in Figure 3-1 to compare these systems, the actual cost increase due to retrofit at Will County appears to have been about 23% over the installed cost of a similar new plant. This compares quite well with the 30% increase predicted by the Catalytic estimate.

The above discussions of limestone scrubbing capital costs applies equally well to lime scrubbing since these processes are substantially the same. Capital investment estimates for other processes which may be available for application in Ohio are also given by Rochelle. Magnesium oxide scrubbing (Chemico) and sodium sulfite scrubbing (Wellman-Power Gas) are both regenerative processes producing an enriched SO_2 stream as a by-product. If this off-gas were converted to sulfur, capital investment for these processes would be comparable to that required for limestone scrubbing for a given application.

3.2 Operating Costs

Flue gas cleaning systems incur a number of significant operating expenses. Detailed operating costs will be discussed only for the case of limestone scrubbing processes. This method of flue gas cleaning is most likely to be generally applicable within the time frame necessary to satisfy Ohio's implementation plan. Since a considerable portion of flue gas cleaning costs arise from fixed capital charges, operating costs for regenerative processes such as magnesium oxide and sodium sulfite scrubbing are in many cases quite comparable to those of limestone or lime scrubbing. Investment, utility, and raw material costs may be slightly higher for the regenerative methods, but these can be offset by credit for by-products and greatly reduced waste disposal requirements.

Rochelle has summarized comparative economics of regenerative and non-regenerative processes in the previously cited paper. These are listed below for a 500 Mw plant burning 3.5% sulfur coal with a 60% load factor. Waste disposal charges for the limestone process were assumed to be \$3.3/metric ton (\$3/ton) of wet sludge. Sulfur credit for the regenerative processes was \$16.5/metric ton (\$15/ton).

Process	Annual Cost (Mills/kwh)
Throwaway	
Lime Scrubbing	2.40
Limestone Scrubbing	2.45
Regenerative	
Magnesium Oxide	2.40
Sodium Sulfite (Wellman Power Gas)	2.65

Operating costs for a flue gas cleaning process may be broken down into three groups: (1) standing plant costs such as labor and maintenance costs, payroll and plant overhead, and fixed charges incurred regardless of whether the plant is operating or not; (2) utility costs such as process water, electricity and steam; and (3) chemicals and raw material costs such as limestone, magnesia, caustic, and solid waste disposal costs.

Among the standing plant costs, the cost of operating labor can be calculated given an estimate for the number of men per shift necessary to operate the equipment and an estimate for labor wages in dollars per man-hour. The cost of supervision is taken as 15% of the operating labor cost. According to standard cost engineering techniques, the cost of maintenance labor and materials can be estimated as 4% of the capital investment, while plant supply costs are approximately 15% of the maintenance labor and material costs (PE-059). Payroll overhead is estimated as 20% of the cost of operating labor and supervision, while plant overhead is estimated as 50% of the sum of the first four standing plant costs. Fixed charges include depreciation, taxes, insurance, and return on investment. Annual fixed charges for the utility

industry are normally about 17-19% of fixed capital investment. If a scrubber were installed on an older existing plant and depreciated over the remaining life of the plant, this charge would be considerably higher. A summary of typical standing plant costs is listed in Table 3-2.

The second group of operating costs includes the cost of utilities consumed only during process operation. Assumed costs for these utilities are listed in Table 3-3. In order to estimate the yearly utility cost, it is first necessary to establish a utility consumption rate for each of the processes. This was done by consulting a number of literature sources for operating cost breakdowns which listed utility consumption for limestone scrubbing processes. The principal sources of this type of information were GR-009, KE-063, and CA-107. Consumption rates of each utility were estimated on a "per ton of coal burned" basis since this is a good indicator of the amount of flue gas to be treated by the scrubber. The consumption rates may then be multiplied by the amount of coal burned by a given boiler to calculate utility costs in dollars per year. Table 3-3 also lists these utility consumption rates.

The third and final group of operating costs is that of raw materials and waste disposal. As in utility cost estimates, the consumption rates of raw materials have been estimated from the literature and from Radian's own limestone scrubbing process design experience. In this case, however, consumption is estimated on a "per ton of sulfur removed" basis since consumption rate is a function of the amount of sulfur in the coal as well as the firing rate. Four tons of limestone are required and 5.2 tons of solid waste (dry basis, not including fly ash) are produced per ton of sulfur treated.

TABLE 3-2

BASIS FOR ESTIMATING STANDING PLANT COSTS FOR FLUE GAS DESULFURIZATION PROCESSES

Cost	Abbreviation	Basis
Direct Operating Labor	DOL	2 men/shift, $5/hour each
Supervision	Su	15% of DOL
Maintenance Labor and Materials	ML&M	4% of Fixed Capital Investment
Plant Supplies	PS	15% of ML&M
Payroll Overhead	PaO	20% of (DOL + Su)
Plant Overhead	PlO	50% of (DOL + Su + ML&M + PS)
Fixed Charges (as a percentage of fixed capital investment)	FC	
Cost of Capital		8%
Insurance		.25%
Interim Replacement		.35%
Federal Taxes		3.16%
State and Local Taxes		2.33%
Depreciation (straight line over useful life of plant)		FCI/Operating Life (years) x 100%

TABLE 3-3

ESTIMATED UTILITY CONSUMPTION RATES AND COSTS FOR A LIMESTONE SCRUBBING PROCESS

UTILITY	CONSUMPTION	COST
Process Water	541 liter/metric ton coal	$.066/1000 liters
Electricity	65 kwh/metric ton coal	$6.75/1000 kwh
Clean Fuel (Oil or Natural Gas)	152,000 Kcal/metric ton coal	$3.17/million Kcal

The delivered cost of limestone is a strong function of plant location as is the cost of solid waste disposal. These factors are discussed in related reports prepared for EPA. Typical costs of $5.5/metric ton ($5/ton) of limestone and $5.5/metric ton ($5/ton) of dry sludge disposal will be assumed for purposes of the following discussion.

3.3 Annualized Costs and Present Worth of Flue Gas Cleaning

The cost information presented in Sections 3.1 and 3.2 may be used to illustrate several important trends in flue gas cleaning economics. Table 3-4 compares annualized costs of flue gas cleaning by limestone scrubbing for three assumed cases.

Boiler A is a small, older unit with 75 Mw capacity. It is operated only 3500 hours per year (40% load factor) since boilers installed before about 1950 are considerably less efficient than newer units. Of the total annual operating cost of 2.2 million dollars, 86% represents fixed charges incurred whether or not the unit is in operation. The annual cost of sulfur removal is $570/metric ton ($518/ton) or 8.3 mills/kwh of electricity produced.

Boiler B is a small newer unit operated 80% of the time. Fixed charges represent 69% of annual operating costs for this unit. The high load factor, however, reduces annual pollution charges to $357/metric ton ($324/ton) sulfur or 4.5 mill/kwh.

Boiler C is a large newer unit also with a relatively high load factor of 80%. The annual operating cost of a flue gas scrubber on this boiler is about 10 million dollars, 64% of which are fixed costs. In this case, the annual cost of sulfur oxides control is $236/metric ton ($215/ton) sulfur or roughly 40% of that for the small older unit.

TABLE 3-4

ANNUALIZED COSTS FOR THREE LIMESTONE SCRUBBING INSTALLATIONS

	Boiler A		Boiler B		Boiler C	
Boiler Size (mw)	75		75		500	
Boiler Age (years)	30		20		5	
Annual Operating Hours	3500 (40%)		7000 (80%)		7000 (80%)	
Annual Coal Burned (metric tons at 5555 cal/g)	127,000		218,000		1,445,000	
Sulfur Content (wt.% S)	3.5		3.5		3.5	
Degree of Control (Equivalent S Content)	0.5		0.5		0.5	
Limestone Scrubbing Capital Investment	$5.5 million		$5.5 million		$26 million	
Raw Material (Limestone)	15,273 tons/yr at $5.5/ton	= $84,000	30,545 tons/yr at $5.5/tons	=$168,000	173,636 tons at $5.5/tons	= $955,000
Utilities						
Water	68,887,000 ℓ/yr at $.066/1000 ℓ	= 4,500	137,774,000 ℓ/yr at $.066/1000 ℓ	= 9,100	760,606,000 ℓ/yr at $.066/1000 ℓ	= 50,200
Electricity	9,100,000 kwh at $6.75/1000 kwh	= 61,400	18,200,000 kwh at $6.75/1000 kwh	= 122,800	103,000,000 kwh at $6.75/1000 kwh	= 695,000
Fuel	19,400x10^6 Kcal $3.17/million Kcal	= 61,600	38,808x10^6 Kcal at $3.17/million Kcal	= 123,200	220,500x10^6 Kcal at $3.17/million Kcal	= 700,000
Labor, Maintenance, and Overhead		= 547,000		= 547,000		= 1,977,000
Sludge Disposal (Dry Basis)	19,818 tons/yr at $5.5/ton	= 109,000	39,636 tons/yr at $5.5/ton	= 218,000	225,454 tons/yr at $5.5/ton	= 1,240,000
Fixed Charges	24.1% of Capital Investment	= 1,326,000	19.1% of Capital Investment	= 1,050,000	16.95% of Capital Investment	= 4,410,000
TOTAL ANNUAL COST		$2,173,500		$2,338,100		$10,027,200
$/metric ton Sulfur Removed		570		357		236
Mills/kwh		8.3		4.5		2.9

All tonnages are metric tons.

Actually, a realistic comparison of flue gas cleaning costs between these three cases must consider the remaining operating life of the boilers. If the useful life of each boiler is assumed to be 40 years, then the sulfur removal benefits for Case A will extend for ten additional years, those of Case B for twenty years, and Case C for thirty-five years.

A common method of considering the total cost of projects extending over a long time span is to calculate the "present worth" of the venture. This method simply "discounts" money spent for operation in future years by a factor which considers the time value of money. For example, if $10,027,200 are required to operate Unit C in 1983, then 4.2 million dollars invested at 8% interest in 1973 would provide for this operating expense. The total amount of money which, invested immediately, would finance the life of the project is the actual "present cost" of pollution control.

Present costs calculated for Boilers A, B, and C are given in Table 3-5. On this basis, the total cost of pollution control on a small old boiler is more than five times that required for a large newer boiler. A small boiler operated at a high load over a 20-year life, however, requires a pollution control expenditure only 2.2 times that for the large new boiler.

The cost penalty resulting from a short operating life at low load is far more significant than that due solely to unit size.

TABLE 3-5

PRESENT COST OF POLLUTION CONTROL

	Boiler A	Boiler B	Boiler C
Capital Investment, $	5.5 million	5.5 million	26 million
Annual Operating Cost, $	2.17 million	2.34 million	10.03 million
Present Cost of Total Expenditure, $	20.05 million	28.65 million	143 million
Cost of Pollution Control			
$/metric ton sulfur	526	219	95
Mills/kwh	7.6	2.7	1.2

4.0 APPLICATION OF TECHNICAL AND ECONOMIC FACTORS TO THE OHIO BOILER POPULATION

The impact of technical and economic factors governing retrofit of flue gas cleaning processes in Ohio may be examined by considering the size, age, and load factor distribution of the coal-fired boiler population in Ohio. Previous investigators (MO-067) have identified twenty-six power plants which consumed 97% of the total coal burned for public power production in Ohio in 1970. Pertinent data for these plants compiled from 1971 FPC reports are summarized in the Appendix.

The age and size distributions of coal-fired generating capacity in Ohio were calculated from these data. This information is summarized in Figure 4-1. About eighty percent of the 1971 Ohio generating capacity is less than twenty years old. Eighty-five percent of the total capacity is accounted for by boilers of 100 megawatts or more each.

Load factors for Ohio generating capacity were also estimated using 1971 F.P.C. data. Here, load factor is defined as the reported annual heat input to a unit divided by its design annual input. These results should correspond in most cases to the fraction of time (annually) during which the units were operated. Figures 4-2 and 4-3 show load factor versus age and size respectively.

Figure 4-2 shows that annual load factors for boilers less than twenty-five years old normally range from about 50% to 85%. The total load factor for this group of boilers is 70%. With the exception of two units, boilers older than twenty-five years have load factors ranging from only 10% up to 55%. The average load factor for this group is around 35%. The reason for this marked difference in operating time between old and new units is

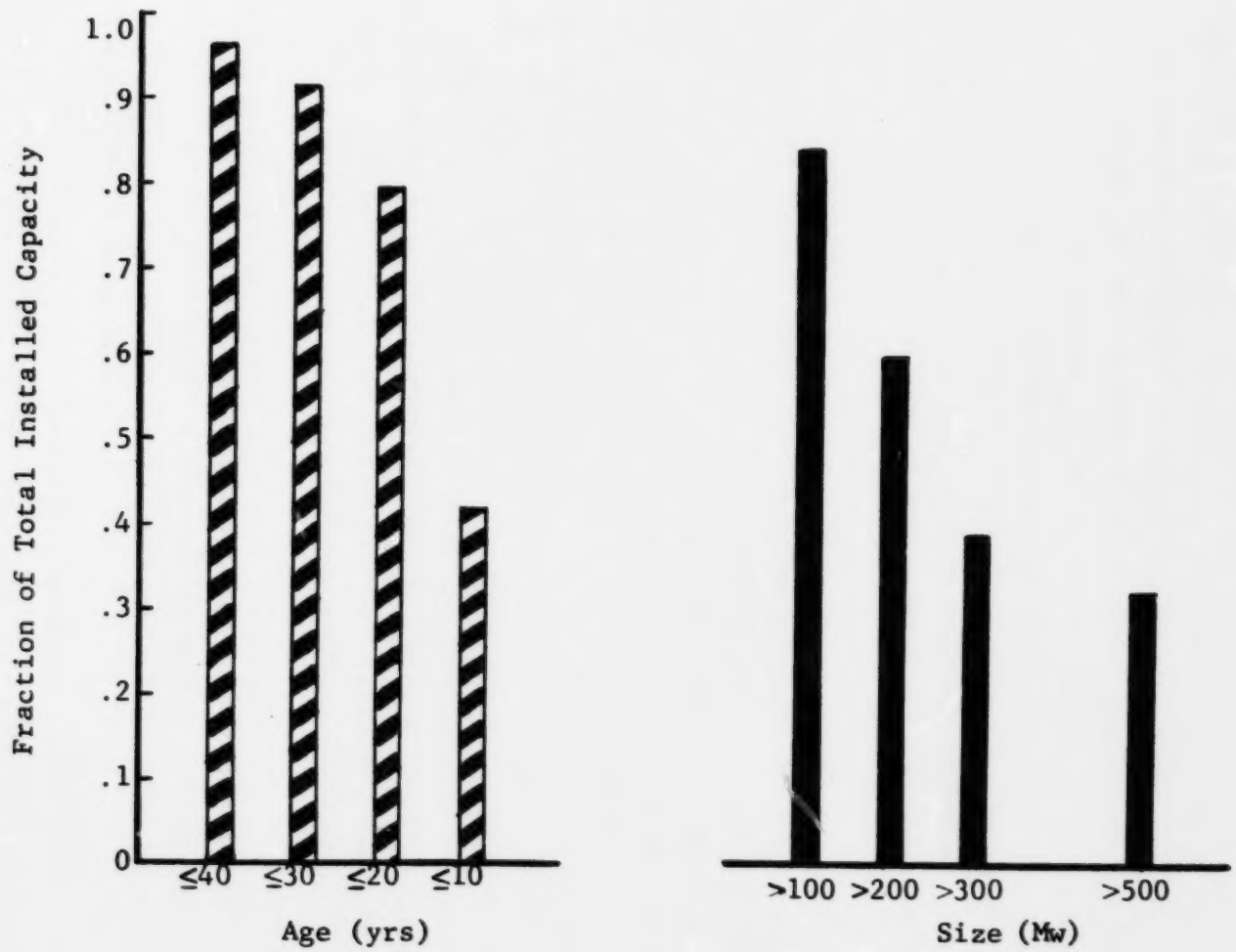

FIGURE 4-1

Age and Size Distributions of Total
Ohio Generating Capacity
(Source - 1971 FPC Data)

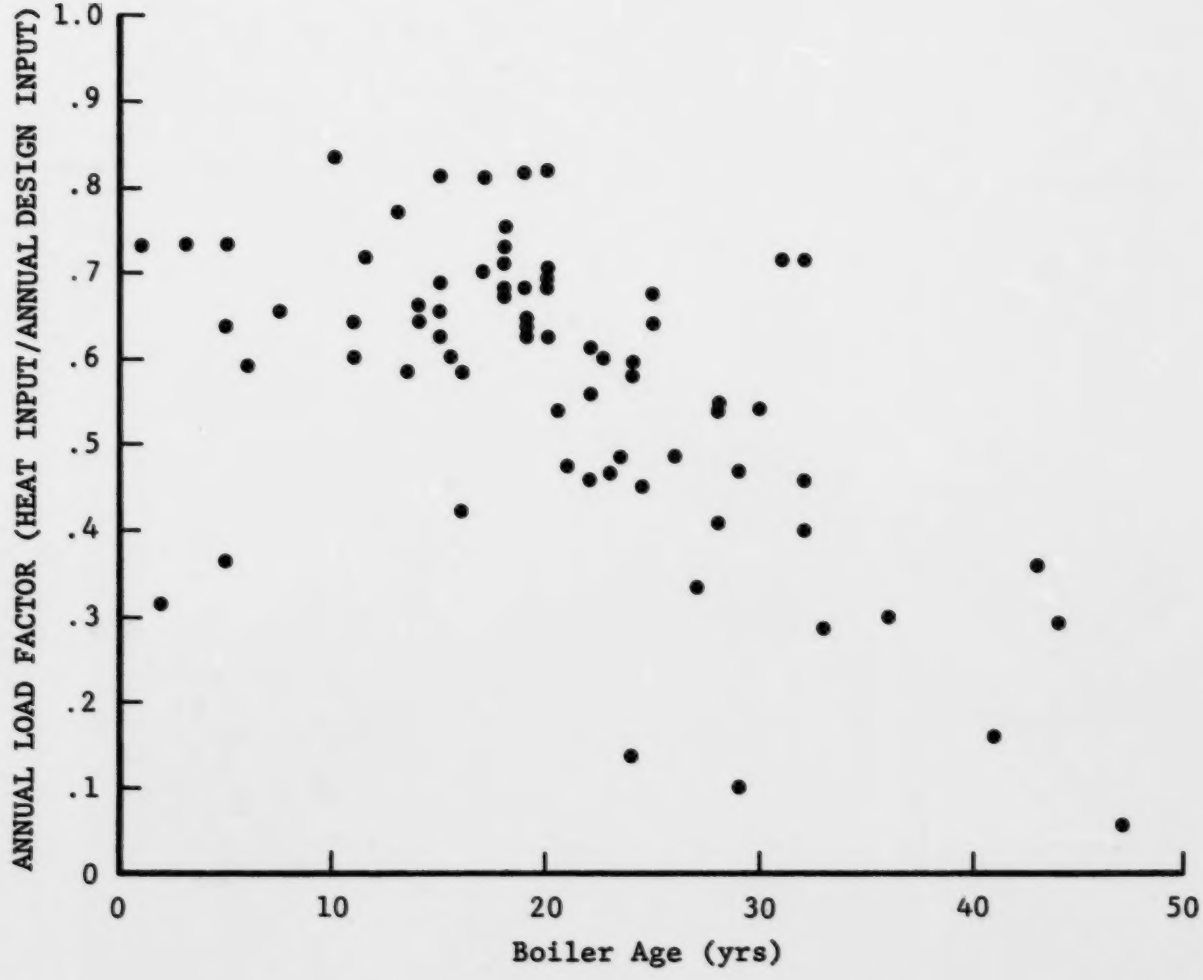

FIGURE 4-2

LOAD FACTOR VERSUS AGE FOR OHIO BOILERS

(Source - 1971 FPC Data)

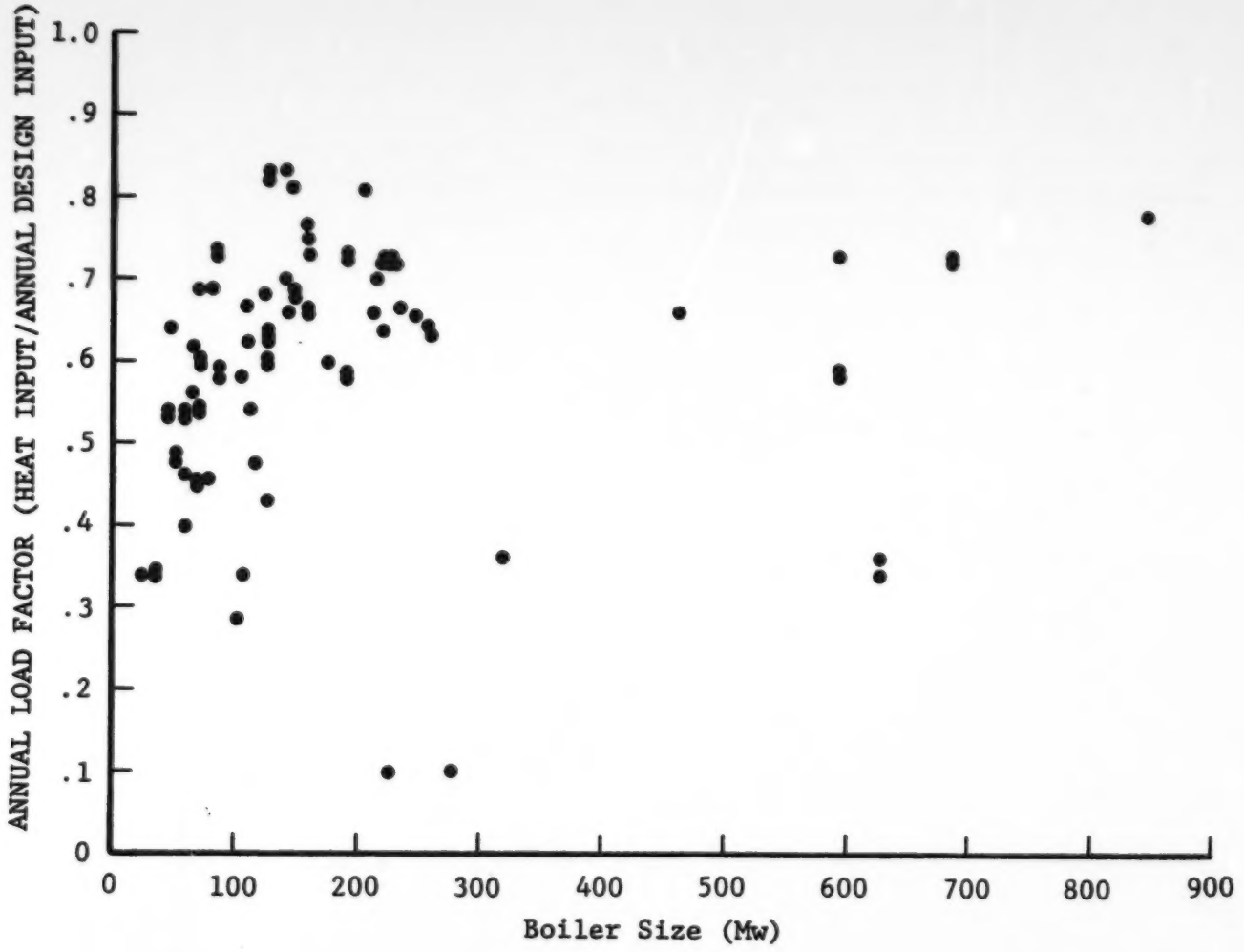

FIGURE 4-3

LOAD FACTOR VERSUS SIZE FOR OHIO BOILERS
(Source - 1971 FPC Data)

that new boilers are significantly more efficient than those constructed before about 1950. To minimize operating costs, a utility will use old units only during periods of peak capacity demand.

Figure 4-3 relates load factor and unit size for Ohio generating capacity. Since there is a strong correlation between boiler age and size, boilers having low load factors are primarily those with less than 100 Mw capacity. However, many small units are used extensively while many old units were not. Boiler size is not necessarily an indicator of probable load factor.

The above description of Ohio coal-fired generating capacity may be combined with the space availability data presented in Section 2.0 to estimate the applicability of flue gas cleaning systems for sulfur oxide control in Ohio.

4.1 Expected Retrofit Space Availability in Ohio

Space requirements for flue gas cleaning equipment were discussed in Section 2.0. A minimum ground area of approximately 1.9 M^2/Mw adjacent to the boiler house and stack appears to be required for installation of control equipment without unreasonable engineering and construction effort. Although space availability can be determined only by inspection of actual plant layouts, the overall technical applicability of flue gas cleaning retrofit in Ohio may be estimated.

The retrofit factors derived in Section 2.0 were applied to the size and age distribution in Figure 4-2 to estimate retrofit space availability for the Ohio boiler population. The fraction of boiler capacity in a given size or age group that could be retrofitted according to the Kellogg data was multiplied by the fraction of total Ohio capacity which is accounted for by the same size or age group to arrive at the probable applicability of flue gas cleaning in Ohio. These results are shown in Figure 4-4. The maximum expected applicability of flue gas cleaning systems represents about 70% of total existing 1971 Ohio capacity. About 60% of the total capacity may be retrofitted if application is limited to boilers twenty years old or less. Application of flue gas cleaning to units 100 Mw and larger would also be practical for about 60% of the total 1971 Ohio generating capacity. These applicability factors are slightly lower than those indicated in the Kellogg survey since the Ohio boiler population includes a larger fraction of capacity in the smaller boiler size ranges.

It should be noted that these factors can only be confidently applied in a statistical sense to a large sample of coal-fired generating capacity. Applicability of flue gas cleaning to individual boilers or plants may be determined only by actual inspection of the site.

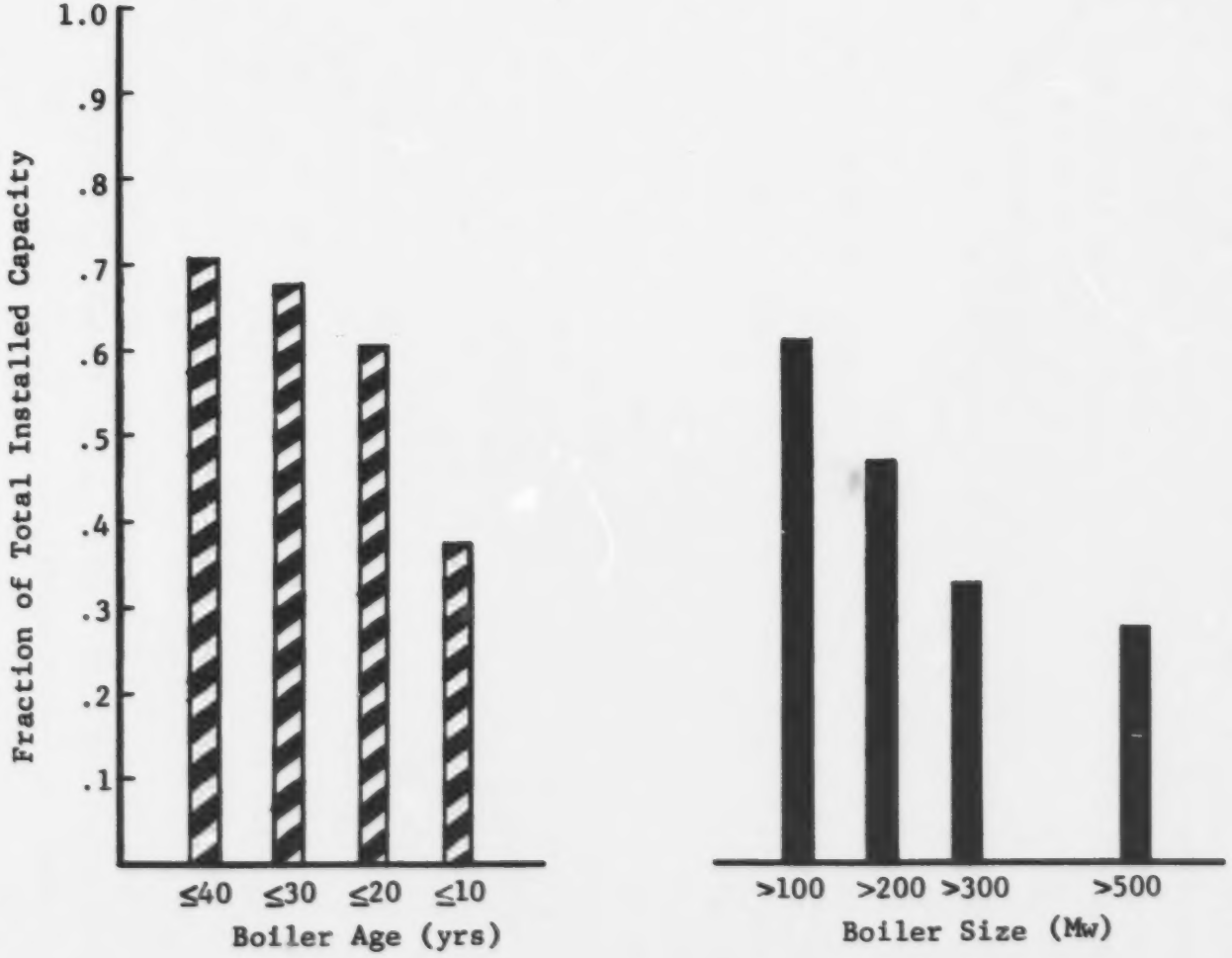

FIGURE 4-4

Age and Size Distribution of
Retrofittable Ohio Generating Capacity

4.2 Estimated Cost of Flue Gas Cleaning for Existing Ohio Boilers

The economic factors outlined in Section 3.0 show that flue gas cleaning costs are somewhat sensitive to unit size and fuel sulfur content, and depend to a greater extent on boiler load factor and operating life. An overall cost for applying a process such as limestone scrubbing in Ohio may be estimated from information describing the size, age, load factor, and retrofitability of 1971 Ohio generating capacity. Table 4-1 summarizes such an estimate.

For each of the boiler age groups, the expected retrofit capacity is shown along with the average unit size, operating life and load factor. An average fuel sulfur content of 3.33 weight percent was calculated from 1971 FPC data for Ohio units. The degree of control is equivalent to an emission of 1.8 Mg SO_2/Kcal (1 lb. SO_2/million BTU) heat input (the 1978 Ohio standard). Fuel consumption was calculated using typical boiler heat rates and a heating value of 6110 cal/gm coal (10,000 BTU/lb coal). Total investment, annual operating charges, and total present cost are shown for each age group.

The total investment cost associated with flue gas cleaning in Ohio is shown in Figure 4-5a as a function of the fraction of total capacity retrofitted. Since smaller units require greater investment per unit capacity, the required investment increases disproportionally as small, older units are included. The retrofitable 70% of total capacity would require a short term capital investment of approximately seven hundred thirty million dollars. Corresponding investment in terms of total present cost of flue gas cleaning are shown in Figure 4-5b.

TABLE 4-1

ESTIMATED COSTS FOR CONTROL OF RETROFITABLE EXISTING 1971 OHIO GENERATING CAPACITY

Boiler Age Group (Years)	0-10	11-20	21-30	31-40
Retrofittable Ohio Capacity (Mw)	6600	4200	1400	300
Number of Units	12	25	21	5
Average Size (Mw)	540	170	66	60
Useful Operating Life (Years)	35	25	15	5
Annual Operating Hours	6000	6000	4725	2900
Annual Coal Burned (million metric tons/year at 6110 Cal/gm)	15.0	10.7	3.2	.43
Sulfur Content (wt %)	3.33	3.33	3.33	3.33
Degree of Control (equivalent sulfur)	.55	.55	.55	.55
Sulfur Removed (1000 metric tons/year)	417	298	89.0	11.2
Capital Investment Average ($/kw)	50	65	75	75
Total ($ million)	330	273	105	22
Annual Costs ($ million)				
Raw Material (limestone)	9.18	6.56	1.96	.25
Utilities				
Water	.53	.38	.11	.02
Electricity	6.58	4.70	1.40	.19
Fuel	7.23	5.16	1.54	.21
Labor, Maintenance, Overhead	24.93	23.34	10.84	2.37
Sludge Disposal	11.93	8.53	2.54	.32
Fixed Charges	55.90	49.40	21.78	7.50
TOTAL ANNUAL COST ($ million)	116.28	98.07	40.17	10.86
Present Cost of Total Expenditure ($ million)	1690	1320	449	65.3
Cost of Pollution Control $/metric ton sulfur	116	117	336	1167
Mills/kwh	1.24	2.07	4.58	15.0

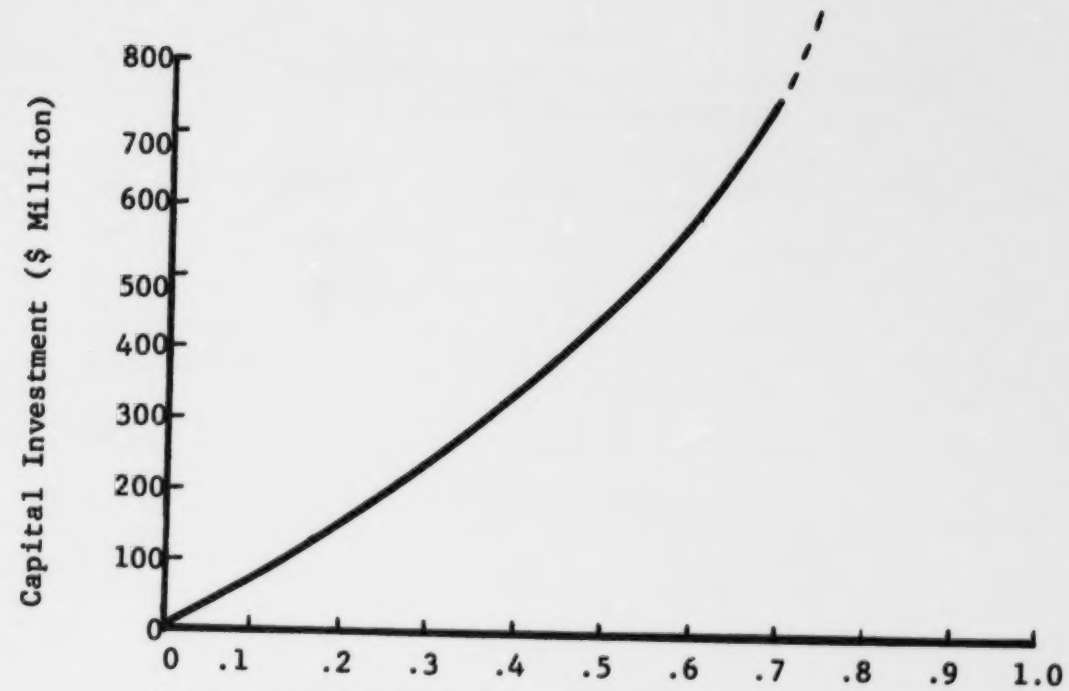

FIGURE 4-5a
Total Investment Cost Versus Capacity Retrofitted

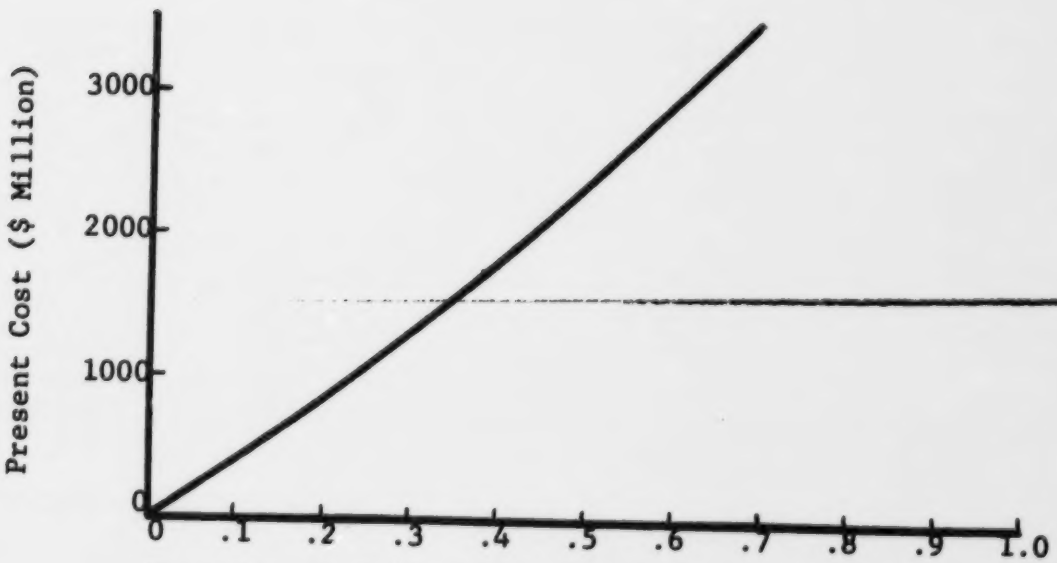

FIGURE 4-5b
Total Present Cost Versus Capacity Retrofitted

The incremental cost trends illustrated in Figures 4-6a and 4-6b are perhaps more important with respect to the applicability of flue gas cleaning in Ohio. The combination of higher unit investment costs, low load factor, and short operating life results in a dramatic increase in "incremental" control costs with the degree of retrofit. Incremental costs are those associated with adding controls to additional plants moving from large new units to small old units. That is, each additional ton of sulfur removal becomes more expensive because of the factors discussed in Section 3.0. Since 60% of the Ohio capacity is less than twenty years old or greater than 100 Mw in unit size, the incremental present cost of flue gas cleaning remains below two mills/kwh for these units. As small, older boilers are included in further retrofit capacity, incremental control costs increase rapidly. This cost increase would presumably make low sulfur fuel purchases or unit shutdown more attractive than flue gas cleaning. While the absolute magnitude of pollution control costs shown here are somewhat uncertain, the illustrated trends are significant effects of relatively firm economic factors.

Summarizing the trends shown here, both capital investment and pollution control costs per unit of electric power or unit of sulfur removal increase inordinately as controls are applied beyond certain practical limitations. The technical and economic factors discussed in previous sections of this report combined with the size and age distribution of Ohio generating capacity lead to a predicted sharp increase in the cost of pollution control beyond application to 60-70% of existing capacity.

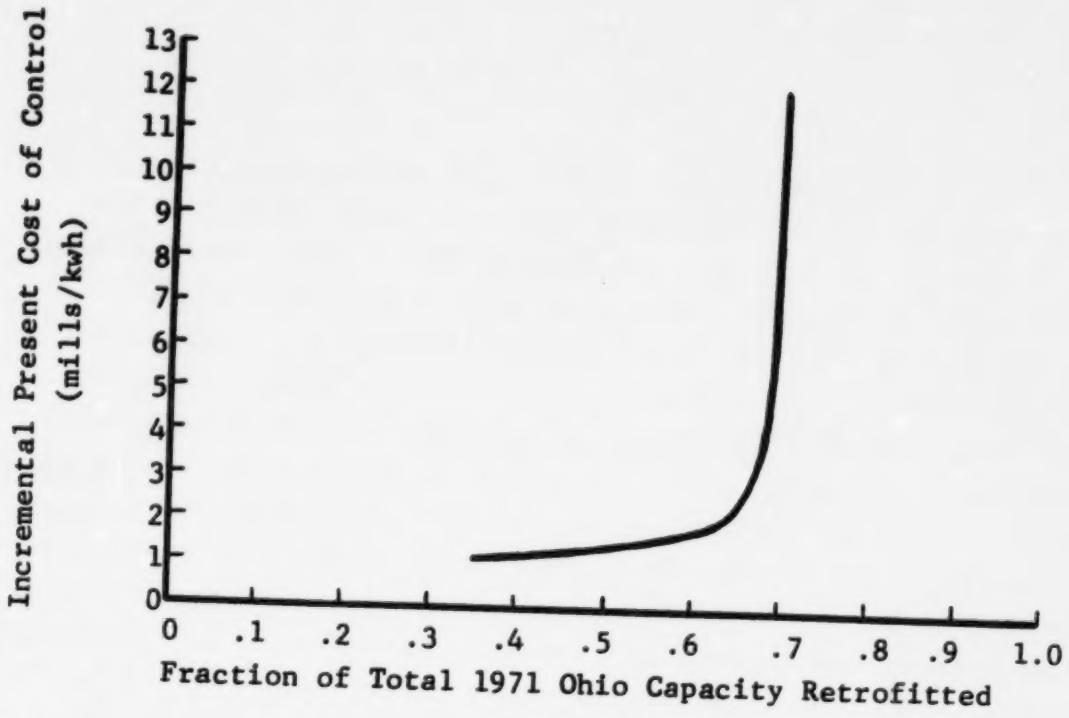

FIGURE 4-6a
Incremental Cost of Control Versus Capacity Retrofitted

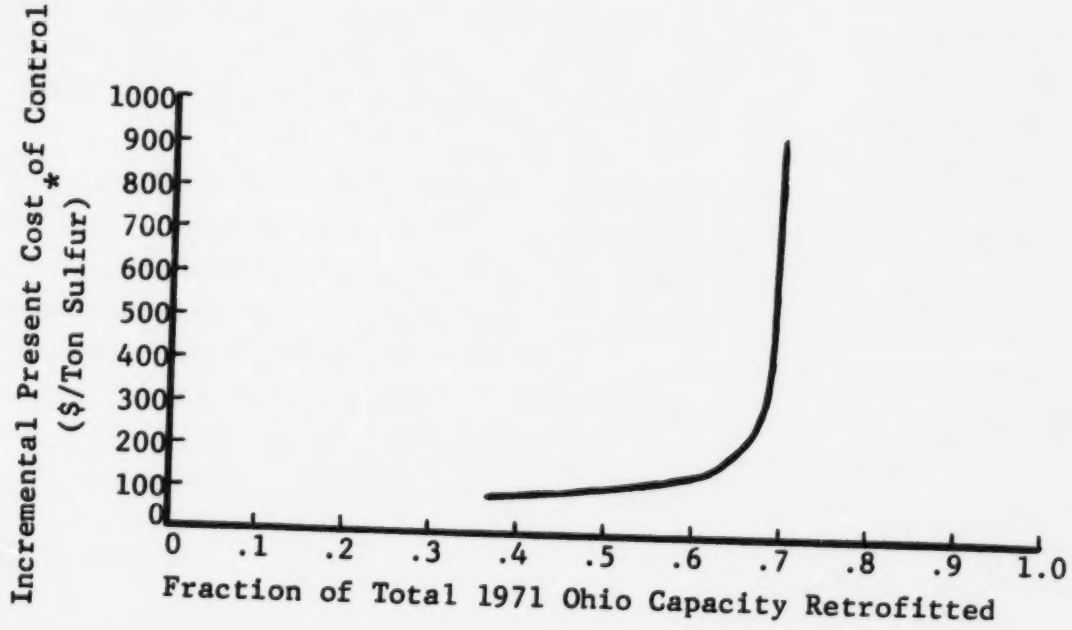

FIGURE 4-6b
Incremental Cost of Control Versus Capacity Retrofitted

*Units are U.S. short tons (1 U.S. short ton = .909 metric tons)

5.0 FACTORS WHICH MAY LIMIT THE RATE OF APPLICATION OF FLUE GAS CLEANING IN OHIO

The discussion in previous sections was primarily concerned with the technical and economic applicability of flue gas cleaning in Ohio. The retrofittability of existing boilers was estimated and expected costs for pollution control presented. Conclusions reached from this type of information can deal only with whether or not flue gas cleaning is a feasible control alternative. The information below is related to the actual rate at which flue gas cleaning may be applied to existing and new capacity.

Since the factors considered here are highly uncertain, no attempt is made to derive an implementation schedule from them. Rather, the intent of this section is merely to demonstrate, using specific data where possible, which of these may become a problem within the time frame specified by the Ohio Air Pollution Regulations.

The first and most obvious limitation on flue gas cleaning is normal lead time required for engineering, procurement, construction, and start-up of such a large, complex unit. This is generally acknowledged to be a minimum of 24 months from the purchase date. The other factors discussed below are those which may cause this normal lead time to be extended.

The situation may become particularly severe in Ohio since a significant fraction (13.5%) of the total U.S. sulfur emissions from coal-fired generating capacity is accounted for by Ohio boilers. A high level of flue gas cleaning investment is thus needed. One must also consider that expanding control activities in neighboring states will compete for capital, labor, vendors, and equipment.

5.1 Capital Requirements

The total annual capital investment of the electric utility industry in the State of Ohio for 1972 was $706 million (from Public Utility Commission of Ohio). The estimated cost for retrofitting 70% of the existing 1971 boiler capacity in Ohio as presented in Section 4.0 is $730 million. In addition to retrofitting existing boilers, new plants will have to be controlled during the same time period. New generating capacity is normally added at an annual rate of 7%. These new boilers will require control systems with an average cost of $40/kw. This new investment in pollution control will be about $50 million/year in Ohio. If pollution control is applied in Ohio from 1973 to 1975, the total investment for SO_2 control for existing and new units would be about $830,000,000. For a five-year period, the total cost is about $980,000,000.

A pollution control investment of this magnitude represents an increase in capital expenditures nearly 60% over that of a normal two-year period or 28% over that for a five-year period beginning at the end of 1973.

Some considerations need obviously be given to the source of such a large increase in capital expenditures.

5.2 Power Availability

The installation of sulfur removal equipment dictates that additional electrical power be generated to run this equipment. In a report by Processes Research, Inc., entitled Flue Gas Cleaning Process Commercial Availability (PR-048), it is estimated that 2 to 7% of the power output of the boilers fitted with SO_2 removal equipment is required to run the equipment. Most power companies do not have sufficient reserve capacity to

supply this additional power. In a report by the Sulfur Oxide Control Technology Assessment Panel entitled Projected Utilization of Stack Gas Cleaning Systems by Steam-Electric Plants (SU-031), it is noted that the Federal Power Commission states that reserves of about 20% of peak load are essential to avoid sporadic power curtailments. Also in this report, the actual reserve capacity for the National Power Survey Region in which Ohio is located (East Central) is given as 16.5% of the estimated peak summer load as of June 27, 1972. Since excess power is not available in Ohio, the retrofit of 12,500 Mw capacity (representing 70% of existing 1971 capacity) would require at least an additional 750 Mw of new capacity to power the retrofit installations in order to avoid power curtailments to the customers. Assuming a cost of $250/kw for the new capacity, as in the Process Research report (PR-048), this would add an additional $190 million investment for new generating capacity to the cost of retrofit flue gas cleaning in Ohio.

5.3 Demand and Supply of Critical Labor Categories in Ohio

Various skilled labor categories have been identified as important to timely construction of flue gas cleaning facilities. Boilermakers and pipe fitters are probably the most critical of these (PR-048). There are 2113 boilermakers in the State of Ohio, which represents 7.16% of the United States total (1970 census). Data on pipe fitters are not available, but it is probable that the State of Ohio has 7% or less of the pipe fitters in the United States since it has only 5.86% of the plumbers and pipe fitters combined (1970 census).

As stated in Section 5.1, the total flue gas cleaning capital expenditure estimated for a two-year application period is $830 million and for a five-year program is $980 million. As stated in the report by Processes Research, Inc. (PR-048), pipe fitter and boilermaker man-hours per $1000 investment in flue gas cleaning are estimated as 10.0 for retrofit and 7.5 for new plant construction. The total boilermaker and pipe fitter man-hours worked in the U.S. in 1971 are also estimated as 318 million. Using these data, the significance of labor requirements for widespread application of flue gas cleaning in Ohio can be estimated. The total pipe fitter and boilermaker man-hours required for sulfur removal for two years of retrofit plus new capacity is about eight million or four million man-hours per year.

This annual man-hour requirement for the two year flue gas cleaning application period is about 1.3% of the total 1971 boilermaker and pipe fitter man-hours worked for the entire United States. To provide the additional labor, the boilermaker and pipe fitter labor force in Ohio would have to increase by nearly 20%.

If the retrofit (plus new capacity) construction were extended over a five-year period, the total man-hours required for sulfur removal are reduced to 1.8 million/yr. This is less than .6% of the 1971 boilermaker and pipe fitter man-hours worked in the United States and corresponds to a required 8% increase in the Ohio boilermaker and pipe fitter labor force.

In telephone conversations on June 12, 1972, between Processes Research, Inc., and the Boilermakers and Pipe Fitters Unions, the labor situation was discussed. It was found that at that time boilermakers were nearly fully employed and unable to obtain sufficient apprentices to replace employees who either retire or die. However, some expansion can be realized by retaining men with related skills such as welders and ironworkers, although this is at least a two-year program. The Pipe Fitters Union reported that they could increase the work force by five to ten percent through retraining men from related fields such as ironworkers, welders, and boilermakers. They pointed out that overall labor efficiency for such an expanded work force might be lowered, however.

5.4 Major Equipment Supplies

In Section 4.0 it was estimated that about 60 boilers in Ohio could be feasibly retrofitted. Should this massive retrofit be implemented, the increased demand for long-lead-time manufactured items such as fans, pumps, and grinding mills may cause significant construction delays.

There are three major producers of large induced-draft fans in the United States (Green Fuel Economizer Co., Buffalo Forge, and Westinghouse). Each of these companies were contacted and it was estimated that if only the fans required for Ohio were ordered in excess of the normal market, then these fans could be available within two years. However, flue gas cleaning retrofit probably will take place across the entire United States. In the previously cited report by Processes Research, Inc., the factors affecting retrofit for 450 boilers across the Nation were studied. It is noted in this report that all three of the major induced-draft fan manufacturers

confirm that if the retrofit construction period for these 450 boilers is five years or more, there should be no problems in delivering the required number of fans. Thus, since the demand for large induced-draft fans probably will increase across the United States, delays in the normal two-year construction period for SO_2 control processes may be expected.

Procuring the large centrifugal pumps required for transporting the scrubbing liquor may also present problems causing significant construction delays. The number of pumps required can be estimated as follows. Typically a boiler produces 5100 actual cubic meters per hour (3000 ACFM) of flue gas per megawatt generating capacity. For a scrubber liquid-to-gas ratio of 8 liters/cubic meter (60 GPM/1000 ACFM) the total rate at which scrubbing liquor must be pumped can be estimated. In Section 4.0 it is estimated that 70% of the existing 1971 generating capacity can be retrofitted. This corresponds to approximately 12,400 Mw. New capacity at a rate of 7% annually must also be controlled, bringing the total controlled generating capacity for 1975 to about 16,400 Mw. This would require a total of 11,166,000 liters/minute (2,950,000 GPM) of scrubbing slurry to be pumped. The total for 1978 is 13,626,000 liters/minute (3,600,000 GPM).

Three of the major manufacturers of large rubber-lined centrifugal pumps were contacted to determine what size pumps are available and to determine how the increase in demand for these pumps would affect the market. Rubber-lined pumps are generally preferred for transport of abrasive slurries. Denver Equipment Company is the only manufacturer of those contacted which makes rubber-lined pumps with a 75,700 liter/min (20,000 GPM) capacity, although the Galigher Company is currently considering producing this type of pump with a capacity as high as 52,990 liter/minute (14,000 GPM). Both Ingersoll-Rand and Galigher Company currently

have the capability to manufacture rubber-lined pumps with capacities of 26,500-30,280 liters/minute (7-8,000 GPM). If the retrofit operations required for Ohio were to be completed in two years and 75,700 liters/minute (20,000 GPM) pumps were used, about 150 of these pumps would be required. If 30,280 liters/minute (8,000 GPM) pumps were used, approximately 370 would be needed in the next two years. Denver Equipment Company optimistically estimates that they can manufacture about 65 rubber-lined pumps of 75,700 liters/minute (20,000 GPM) capacity in two years. This is only about 40% of the total required for the two-year retrofit program.

One of the vendors, Ingersoll-Rand, currently manufactures about 200 rubber-lined pumps [30,280 liters/minute (8,000 GPM capacity)] per year. To supply only one-fourth of the pumps required for a two-year flue gas cleaning application period in Ohio, they would have to increase their production by about 25%. This is only for the pumps required in Ohio. The demand for these pumps should increase across the United States, thus making the production of the required number of pumps even more difficult. These figures indicate that it would be extremely difficult to manufacture the required number of pumps for a two-year retrofit program.

If the time period for retrofit operations were extended to five years, the total required number of 75,700 liters/minute (20,000 GPM) capacity pumps is about 180. If 30,280 liters/minute (8,000 GPM) capacity pumps are used, the total number required is about 450. Vendor data indicate that there should be no problems producing this number of pumps over a five-year period.

At least one other major piece of equipment, grinding mills, requires a long lead time for manufacture. These mills

are used to grind raw limestone for the limestone wet scrubbing process. Two manufacturers of ball mills were contacted (Allis-Chalmers and Denver Equipment Company). These companies indicate that there should be no problems in manufacturing their share of the ball mills required over a two-year retrofit period.

5.5 Tie-In Requirements

Although most of the construction of retrofit sulfur removal equipment can be accomplished independent of boiler operation, some down-time will be realized for connecting the system to the existing equipment. Typically, electric power demands peak in the winter and summer seasons due to the extreme temperatures encountered then. Thus, any down-time for retrofit operations would have to be scheduled for the off-peak fall and spring months. A typical generating plant is scheduled for routine maintenance at least once a year. This usually requires 1-3 weeks of down-time. The Sulfur Oxide Control Technology Assessment Panel Report (SU-031) states that by all estimates this would not be a long enough period for installation of even a pre-assembled sulfur-oxide removal system. This panel also reports, however, that once every 4-5 years, a plant is scheduled for maintenance requiring 5-8 weeks, which should be adequate time for tying in a scrubbing system if scheduling is carefully planned. Thus, on the average, a maximum of 20% of the generating capacity could be retrofitted in one year. This panel also states that due to probable increases in construction time early in the expansion of the SO_x control industry, it is likely that less than 20% of the generating capacity can be retrofitted in any one year.

5.6 Availability of Engineering and Design Services

In a report by Catalytic, Inc., entitled Preliminary Problem Definition SO_x Control Process Utilization (JA-054), the effect of increased demand for retrofit flue gas cleaning over the United States on engineering and design firms was examined. Since engineering design is independent of the location of the actual construction, this study should be applicable to the retrofit situation in Ohio.

It was estimated in this study that the projected volume of total industrial construction for 1972 to 1975 is $74 billion. It was also estimated that the total installed costs of flue gas desulfurization for the entire United States would be four billion. Ten percent of this total was assumed to be for design costs and the remaining $3.6 billion for construction costs. It was concluded that since this $3.6 billion was only five percent of the projected industrial construction, it was achievable by normal construction contactor growth.

The 10% assumed for design costs represents only a 3% increase in the business volume for 1972-1975 of the leading design firms as reported by Catalytic, Inc. It was concluded that this additional growth could be realized through the normal growth of design firms.

5.7 Vendor Capability

The number of vendors offering large-scale flue gas cleaning systems is limited. The Sulfur Oxide Control Technology Assessment Panel Report (SU-031) states that there are approximately fifteen scrubbing system vendors. However, it also states that there are only three or four of these vendors with

sufficient experience, manpower, and corporate backing to expand rapidly. Mr. George A. Jutze, President of Pedco-Environmental, has talked with representatives of three of the major scrubbing system vendors (Combustion Engineering, Chemical Construction Co., and Cottrell Environmental Systems) about the availability of their systems. He reports that they feel that they only can produce 3-5 systems/year each. Mr. Jutze also stated that the three vendors felt they could only have a combined total of 30 systems on line in Ohio within three years after contract award. This represents slightly less than 50% of the existing 1971 boilers in Ohio which can be feasibly retrofitted as stated in Section 4.0.

6.0 SUMMARY

Although flue gas cleaning technology is now available for general use there are several limitations on both the extent of practical application and the rate at which systems may be installed. The technical and operational aspects of flue gas cleaning systems are not discussed in this report as they are covered in related reports; therefore, this paper places the emphasis on process applicability. The controlling factor appears to be the availability of ground space for equipment located immediately adjacent to the boilers and stacks. A minimum ground area of approximately 1.9 M^2/Mw (20 ft^2/Mw) adjacent to the boiler house and stack appears to be required for installation of control equipment without unreasonable engineering and construction effort. Although space availability can be determined only by inspection of actual plant layouts, the overall technical applicability of flue gas cleaning retrofit in Ohio may be estimated.

The retrofit factors were derived and applied to the size and age distribution in Figure 4-2 to estimate retrofit space availability for the Ohio boiler population. The fraction of boiler capacity in a given size or age group that could be retrofitted according to the Kellogg data was multiplied by the fraction of total Ohio capacity which is accounted for by the same size or age group to arrive at the probable applicability of flue gas cleaning in Ohio. These results show that the maximum expected applicability of flue gas cleaning systems represents about 70% of existing 1971 Ohio capacity. About 60% of the total capacity may be retrofitted if application is limited to boilers twenty years old or less. Application of flue gas cleaning to units 100 Mw and larger would also be practical for about 60% of the total 1971 Ohio generating capacity.

The economic factors outlined in this paper show that flue gas cleaning costs are somewhat sensitive to unit size and fuel sulfur content and depend to a greater extent on boiler load factor and operating life. An overall cost for applying a process such as limestone scrubbing in Ohio may be estimated from information describing the size, age, load factor, and retrofittability of 1971 Ohio generating capacity. Table 6-1 summarizes such an estimate.

For each of the boiler age groups, the expected retrofit capacity is shown along with the average unit size, operating life, and load factor. An average fuel sulfur content of 3.33 weight percent was calculated from 1971 FPC data for Ohio units. The degree of control used to estimate capital and operating costs is equivalent to an emission of 1.8 mg SO_2/Kcal [1 lb. SO_2/million BTU heat input or an average of 85% removal of SO_2]. Fuel consumption was calculated using typical boiler heat rates and a heating value of 5,555 cal/gm coal (10,000 BTU/ lb coal). Total investment, annual operating charges, and total present cost are shown for each age group.

These data point out that the cost for pollution control increases rapidly for older, smaller boilers. While the absolute magnitude of pollution control costs here are somewhat uncertain, the illustrated trends are significant effects of relatively firm economic factors.

As dicussed, there are no technical or economic factors that inhibit the application of flue gas cleaning systems to some 60-70% of the boiler population of Ohio. There are other outside factors that will certainly affect the rate of application of these systems in Ohio. These factors are:

TABLE 6-1

ESTIMATED COSTS FOR CONTROL OF RETROFITABLE EXISTING 1971 OHIO GENERATING CAPACITY

Boiler Age Group (Years)	0-10	11-20	21-30	31-40
Retrofittable Ohio Capacity (Mw)	6600	4200	1400	300
Number of Units	12	25	21	5
Average Size (Mw)	540	170	66	60
Useful Operating Life (Years)	35	25	15	5
Annual Operating Hours	6000	6000	4725	2900
Annual Coal Burned (million metric tons/year at 6110 Cal/gm)	15.0	10.7	3.2	.43
Sulfur Content (wt %)	3.33	3.33	3.33	3.33
Degree of Control (equivalent sulfur)	.55	.55	.55	.55
Sulfur Removed (1000 metric tons/year)	417	298	89.0	11.2
Capital Investment Average ($/kw)	50	65	75	75
Total ($ million)	330	273	105	22
Annual Costs ($ million)				
Raw Material (limestone)	9.18	6.56	1.96	.25
Utilities				
Water	.53	.38	.11	.02
Electricity	6.58	4.70	1.40	.19
Fuel	7.23	5.16	1.54	.21
Labor, Maintenance, Overhead	24.93	23.34	10.84	2.37
Sludge Disposal	11.93	8.53	2.54	.32
Fixed Charges	55.90	49.40	21.78	7.50
TOTAL ANNUAL COST ($ million)	116.28	98.07	40.17	10.86
Present Cost of Total Expenditure ($ million)	1690	1320	449	65.3
Cost of Pollution Control $/metric ton sulfur	116	117	336	1167
Mills/kwh	1.24	2.07	4.58	15.0

1. Normal lead time required for engineering, procurement, construction, and startup (Generally a minumum of 24 months from the purchase date). The situation may become particularly severe in Ohio since a significant fraction (13.5%) of the total U.S. sulfur emissions from coal-fired generating capacity is accounted for by Ohio boilers. A disproportionate level of flue gas cleaning investment is thus needed. One must also consider that expanding control activities in neighboring states will compete for capital, labor, vendors, and equipment.

2. Power availability. Boilers fitted with SO_2 removal equipment will require 6% of the power output to run the control equipment. Thus, the application of these systems will result in a decrease in the net power generation of the station.

3. Capital requirement. The pollution control investment required for retrofitting 70% of the existing 1971 boiler capacity represents an increase in capital expenditures nearly 60% over that of a normal two-year period and 28% over that for a five year period beginning at the end of 1973.

4. Demand and supply of critical labor categories in Ohio. The total pipe fitter and boilermaker man-hours required for sulfur removal for two years of retrofit plus new capacity is about eight million or four million man-hours per year. This annual man-hour requirement for the two year flue gas cleaning application period is about 1.3% of the total 1971 boilermaker and pipe fitter man-hours worked for the entire United States. To provide the additional labor, the boilermaker and pipe fitter labor force in Ohio would have to increase by nearly 20%.

   If the retrofit (plus new capacity) construction were extended over a five-year period, the total man-hours required for sulfur removal are reduced to 1.8 million/yr. This is less than 16% of the 1971 boilermaker and pipe fitter man-hours worked in the United States and corresponds to a required 8% increase in the Ohio boilermaker and pipe fitter labor force.

5. Major equipment supplies. In this paper it was estimated that about 60 boilers in Ohio could be feasibly retrofitted. Should this massive retrofit be implemented, the increased demand for long-lead-time manufactured items such as fans, pumps, and grinding mills may cause significant construction delays.

6. Tie-in requirements. The Sulfur Oxide Control Technology Assessment Panel Report (SU-031) states that 1-3 weeks would not be a long enough period for installation of even a pre-assembled sulfur-oxide removal system. This panel also reports, however, that once every 4-5 years, a plant is scheduled for maintenance requiring 5-8 weeks, which should be adequate time for tying in a scrubbing system if scheduling is carefully planned. Thus, on the average, a maximum of 20% of the generating capacity could be retrofitted in one year. This panel also states that due to probable increases in construction time early in the expansion of the SO_2 control industry, it is likely that less than 20% of the generating capacity can be retrofitted in any one year.

All of these data indicate that some 70% of the 1971 Ohio generating capacity can be controlled by flue gas desulfurization and that a massive program to accomplish this in Ohio would be difficult to accomplish by 1978.

BIBLIOGRAPHY

CA-107 Calvin, E. L., A Process Cost Estimate for Limestone Slurry Scrubbing of Flue Gas, 2 Pts, EPA-R2-73-K18a,b., Charlotte, N.C., Catalytic, Inc., 1973.

GR-009 Gressingh, L. E., et al., The Development of New and/or Improved Aqueous Processes for the Removal of SO_2 from Flue Gases, Final Report Vol. 1, Contract No. PH-86-68-77, Azusa, Ca., Aerojet-General Corp., Envirogenics Div., 1970.

JA-054 Jain, L. K., et al., Preliminary Problem Definition SO_x Control Process Utilization, EPA Contract 68-02-0241, Charlotte, N.C., Catalytic, Inc., 1972.

KE-063 Kellogg, (M.W.) Co., Research and Engineering Development Evaluation of SO_2-Control Processes, Task #5, Final Report, PB 204 711, Piscataway, N. J., 1971.

KE-083 Kellogg, (M.W.) Co., Applicability of SO_2-Control Processes to Power Plants, EPA R2-72-100, Piscataway, N. J., 1972.

MO-067 Morrison, Ray, EPA, NERC-RTP, Personal Communication, August 1973.

PE-059 Peters, Max S., Plant Design and Economics for Chemical Engineers, 2nd Edition, New York, McGraw-Hill, 1968.

PR-048 Processes Research, Inc., Industrial Planning and Research, Flue Gas Cleaning Process Chemical Availability, Final Report, Cincinnati, Ohio, 1972.

RO-082 Rochelle, Gary T., "Economics of Flue Gas Desulfurization", Presented at the Flue Gas Desulfurization Symposium, New Orleans, Louisiana, 14-17 May 1973.

SU-031 Sulfur Oxide Control Technology Assessment Panel (SOCTAP), Projected Utilization of Stack Gas Cleaning Systems by Steam-Electric Plants, Final Report, April 1973.

APPENDIX

SOURCE: 1971 FPC Data

Power System	Power Plant	Stack	Existing Generators	No. of Boilers	Capacity (Mw)	Age	1971 † Fuel Burned Coal/Oil/Gas	Approximate Load Factor Coal/Oil/Gas	Coal Sulfur	Tons SO_2 Emitted
Cincinnati Gas and Electric	Beckjord	1	1	1	115	21	272-491	.48/.01	2.9	15,026
		2	2	1	112	20	289/113	.62/<.01	2.9	16,004
		3	3	1	125	19	319/584	.62/.01	2.9	17,662
		4	4	1	163	15	458/811	.66/.01	2.9	25,347
		5	5	1	245	11	1759/651	.66/<.01	2.9	97,264
			6	1	461	4				
	Miami Fort	1	1	3	60	48				
		2	2	3	60	47	96/76	.17/<.01	3.7	6,650
			3	2	65	35				
		3	4	2	65	31	305/197	.41/<.01	3.7	21,142
			5	2	100	24				
		4	6	1	163	13	485/55	.77/<.01	3.7	33,589
Cleveland Electric Illuminating Co.	Ashtabula	1-3	1-4	6	200	43	303	.36	3.3	19,000
		4	5	1	256	15	667	.63	3.3	41,812
	Avon Lake	1-4	1-5	8	190	47	60	.06	2.6	2,984
		5	6	1	86	24	230	.58	2.6	11,380
		6	7	1	86	24	235	.59	2.6	11,632
		7	8	1	233	14	591	.64	2.6	29,177
		8	9	1	680	3	1782	.73	2.6	88,019
	East Lake	1	1	1	123	20	396	.82	3.0	22,569
		2	2	1	123	20	325	.68	3.0	18,450
		3	3	1	123	19	395	.82	3.0	22,501
		4	4	1	208	17	655	.81	3.0	37,353
		5	5	1	680	1	1752*	.73	3.0	99,860
	Lakshore	1	14	1	60	32	113	.40	2.9	6,214
		2	15	1	60	32	131	.46	2.9	7,228
		3	16	1	69	22	184	.56	2.9	10,115
		4	17	1	69	22	201	.61	2.9	11,074
		5	18	1	256	11	661	.64	2.9	36,427

*1972 consumption

† Coal consumption in 1000 tons/year
Oil consumption in 1000 gallons/year
Gas consumption in million ft^3/year

Power System	Power Plant	Stack	Existing Generators	No. of Boilers	Capacity (Mw)	Age	1971 Fuel Burned Coal/Oil/Gas	Approximate Load Factor Coal/Oil/Gas	Coal Sulfur	Tons SO_2 Emitted
Columbus and Southern Ohio Electric	Conesville	1	1	1	147	14	826	.68	4.5	70,614
			2	1	147	16				
		2	3	1	174	11	430	.60	4.5	36,552
		3	4	1	842	0	2457*	.78	4.5	210,074
	Picway	6	1,2	1	24	38	303	~.33	3.7	22,400
		7	3	1	35	28				
		8	4	1	35	24				
		9	5	1	105	18				
	Poston	1	1	1	50	24	225	.48	2.1	8,976
			2	1	50	23				
		2	3	1	77	21	410	.69	2.1	16,357
			4	1	71	19				
	Walnut				75	?				
Dayton Power and Light	Hutchings	1	1	1	69	25	261//34	.45//<.01	1.2	5,957
			2	1	69	24				
		2	3	1	69	23	346//53	.60//<.01	1.2	7,899
			4	1	69	22				
		3	5	1	69	21	289//87	.54//<.01	1.2	6,599
			6	1	69	20				
	Stuart	1	1	1	610	3			3.5-5.0	
		2	2	1	610	2			3.5-5.0	
	Tait	1		2	75	36	100//304	.30//.04	1.6	3,041
		2		2	75	33	92//23	.28//<.01	1.6	2,796
		3	4	1	147	15	452//8	.81//<.01	1.6	13,750
		4	5	1	147	14	366//14	.66//<.01	1.6	11,129
Ohio Edison	Burger	1	1	2	62	29	131	.47	3.2	7.994
		2	2	2	62	26	135	.48	3.2	8,177
		3	3	2	100	23	213	.47	3.2	12,930
		4	4	1	159	18	445	.73	3.2	27,059
		5	5	1	159	18	456	.75	3.2	27,721

Power System	Power Plant	Stack	Existing Generators	No. of Boilers	Capacity (MW)	Age	1971 Fuel Burned Coal/Oil/Gas	Approximate Load Factor Coal/Oil/Gas	Coal Sulfur	Tons SO_2 Emitted
Ohio Edison (cont.)	Edgewater	2	2,3	2	175	24	105	.13	2.9	5,779
		3	4	1	105	16	234	.58	2.9	12,914
	Gorge	2	6	1	44	30	109	.54	3.5	7,261
		3	7	1	44	25	129	.64	3.5	8,584
	Niles	1	1	1	125	19	313	.63	2.8	16,665
		2	2	1	125	19	321	.64	2.8	17,059
	Sammis	1	1	1	185	14	850	.58	2.7	43,610
			2	1	185	13				
		2	3	1	185	12	1061	.72	2.7	54,422
			4	1	185	11				
		3	5	1	317	6	1261	.37	2.7	64,676
			6	1	623	4				
		4	7	1	623	2	710	.32	2.7	36,408
	Toronto	1	1-4	1	140	45				
		2		1						
		3		1						
		4		1						
		5		1						
		7		1						
		8		1						
		12	5	1	44	33	468	.54	2.4	21,352
			6	1	66	24				
			7	1	66	24				
Ohio Power	Cardinal	1	1	1	590	6	1294 | 4150	.59/<.01	2.9	71,319
		2	2	1	590	6	1290	.59/<.01	2.9	71,119
	Muskingum	1	1	1	213	20	658/134	.70/<.01	4.9	61,242
		2	2	1	213	19	621/143	.66/<.01	4.9	57,845
		3	3	1	225	16	1187/298	.60/<.01	4.9	110,477
			4	1	225	15				
		5	5	1	591	5	1726/1386	.73/<.01	4.9	160,707

Power System	Power Plant	Stack	Existing Generators	No. of Boilers	Capacity (Mw)	Age	1971 Fuel Burned Coal/Oil/Gas	Approximate Load Factor Coal/Oil/Gas	Coal Sulfur	Tons SO_2 Emitted
Ohio Power (cont.)	Philo	2,3	3	3	~100	44	147	.29	3.9	10,858
		4	4	1	80	32	294	.72	3.9	21,762
		5	5	1	80	31	293	.72	3.9	21,680
		6	6	1	125	16	226	.42	3.9	16,716
	Tidd	1,2	1	1	111	28	260	.54	3.0	14,848
		3	2	1	111	25	318	.67	3.0	18,145
Ohio Valley Electric	Kyger Creek	1	1	1	217	18			3.9	
			2	1	217	18			3.9	
		2	3	1	217	18	3122	.71	3.9	243,000
		3	4	1	217	18			3.9	
			5	1	217	18			3.9	
Toledo Edison	Acme	16	2	1	72	22	155	.46	2.6	7,656
		4	5	3	270	32	228	.10	2.6	11,360
			6	2	225	24				
	Bay Shore	1	1	1	140	18	341	.66	2.1	13,620
		2	2	1	140	17	361	.70	2.1	14,378
		3	3	1	140	10	391	.83	2.1	15,611
		4	4	1	218	5	460	.63	2.1	18,339

* 1972 data.